Fractured Shale Gas Reservoir Performance Study—An Offset Well Interference Field Test

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Summary

Gas-production characteristics of naturally fractured Devonian shale have been quantified through a three-well interference field test by use of an established producing well and two offsets placed on the primary and secondary regional fracture trends relative to the producer. Three individual shale zones were evaluated simultaneously by buildup, drawdown, and pulse tests to investigate reservoir gas flow characteristics, natural fracture properties, and gas storage and release mechanisms.

Test results show severe permeability anisotropy, indicating elliptical drainage pattern with an 8:1 axis ratio. Essentially all gas is stored in a sorbed state in the shale matrix and is transported toward the wells through the native fracture system.

Introduction

The Devonian shales of the Appalachian basin underlie approximately 68,000 sq miles [175 000 km^2] from New York to Tennessee. These massive shales range in thickness from a few feet at the basin margin outcrops to thousands of feet at the basin center, and are made up of both organically lean ("gray") and rich ("brown") intervals. The shales contain natural gas in considerable quantity, primarily held in solution in solid organic constituents (kerogen) of the shale matrix, which makes the gas resource truly "unconventional." Recent resource estimates for the Appalachian basin shales range from 585 to 2,500 Tcf [16.5×10^{12} to 70.8×10^{12} m^3] of natural gas in place,[1,2] but because of the extremely low matrix permeability of the shale, gas is often not economically recoverable by conventional industry practice. The approximately 12,000 wells drilled to date historically have recovered only about 3 Tcf [0.08×10^{12} m^3] over the last 50 years.

The Appalachian basin shales are considered blanket formations because discrete members are correlative over wide geographic areas. However, even though stratigraphically continuous and gas-containing across their extent, the Devonian shales do not produce uniformly when drilled. Current commercial production is a function of connecting the well with the primarily vertical natural fracture systems present in the shale, which form gathering and transportation networks to move gas from the matrix to the wellbore. Historical production has been limited to discrete areas where natural fracture density was high enough to support development.

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The Eastern Gas Shales Project (EGSP) is a long-term R&D effort by the U.S. DOE to improve overall gas recovery from the shale and to stimulate development of the resource by the private sector. An important part of the R&D thrust has been the development of a technical data base on shale characteristics and production behavior. The offset well test (OWT) described in this paper is a field experiment conducted to improve understanding of the basic gas-production mechanism of this unconventional reservoir. The test project was designed to investigate both qualitatively and quantitatively the gas-production characteristics of the shale in an area of natural fracturing and commercial development, and used a series of reservoir interference tests to achieve the test objectives.

Specifically, the experiment addressed the following objectives.

1. Investigate the flow mechanics of gas in shale matrix and fractures.
2. Determine fracture orientation and distribution.
3. Determine how gas is stored in and released from the shale.
4. Verify the existence of directional drainage patterns and their impact on production practice.

A three-well pattern was developed, consisting of an existing gas well with a 22-year production history and two newly drilled holes offsetting the producer by 120 and 90 ft [36.6 and 27.4 m], respectively, on the major and secondary directional fracture trends predicted for the test area. The interference series was conducted by perturbing the shale reservoir in the base well and monitoring the effects in the offsets. Fig. 1 shows a schematic of the OWT layout and instrumentation used during the interference testing. Earlougher[3] provides a thorough description of interference testing, as well as many references on the subject.

Site Selection

The established producer (control well) used in the OWT formed an important part of the experiment and was carefully selected. During the test planning phase, design criteria were developed to define well parameters required for the planned interference tests. Table 1 lists these requirements. After a criteria review of available wells in the general area of interest, the site prospects

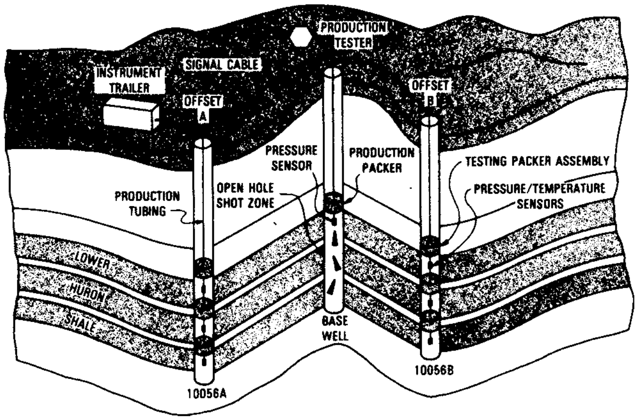

Fig. 1—Offset well test schematic.

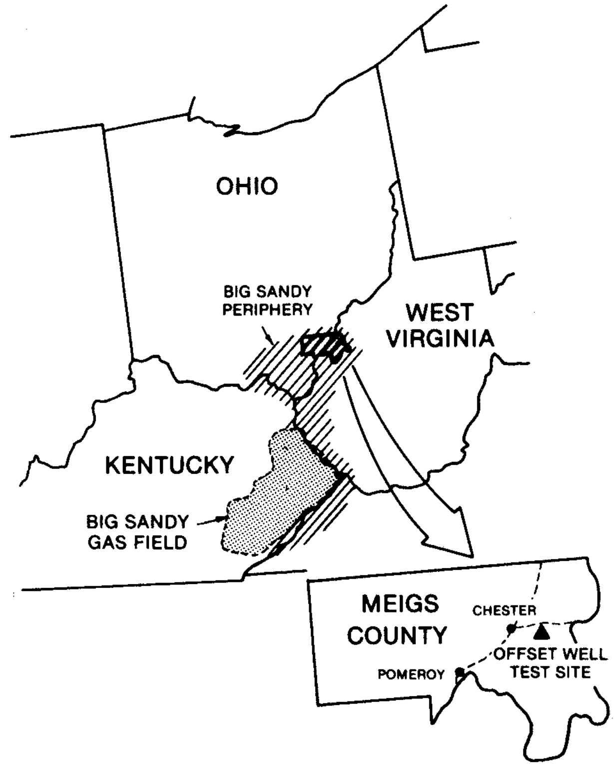

Fig. 2—Field site location.

TABLE 1—CONTROL WELL SELECTION CRITERIA

1. The well is located along a proven producing trend in an area of established gas production.
2. No producing wells exist within approximately 3,000 to 5,000 ft [914 to 1524 m] of the well.
3. The shale pay zone is located at a depth of 1,000 to 4,000 ft [304.8 to 1219.2 m] to minimize offset drilling costs and testing problems.
4. A suite of logs is available for the control well or other wells in the area.
5. The well completion method is openhole and by wellbore shot to eliminate directional inflow bias.
6. There should be a sustained pressure/production history of at least 2 to 5 years.
7. Production rates and downtime information must be accurate with current producing rates preferably of 50 Mcf/D [0.014×10^3 m^3/d] or more.
8. The lower limit on initial reservoir pressure should be 400 psi [2.76 kPa].

were narrowed to two wells—one in Mingo County, WV, and the other in Meigs County, OH. The final site selection was made on the basis of reservoir model simulations of interference-test response after performing four week-long pressure buildup tests in both candidates and history-matching both buildup test and well production history. At each site, the test performance predictions then were used to estimate the minimum interference-test duration needed to transmit an interpretable pressure signal from the control well to the offsets over specific well-to-well distances. Other selection considerations included the availability of road access, steepness of site terrain, offset well depths, and other construction-related costs associated with each site. In both predicted response signal strength and speed of arrival as well as cost factors, the Meigs County site proved superior, and the E.C. Newell Well 10056 on Columbia Gas Transmission Corp. lease acreage was chosen for the experiment. The site location is shown in Fig. 2.

Reservoir Model and Test Plan

The reservoir model, Simulator for Unconventional Gas Resource (SUGAR)[4] was used throughout test planning and later for interference-data analysis. SUGAR was developed by the EGSP specifically to study gas reservoirs in Devonian shale. The core of this model is a radial gas simulator, wherein the external drainage radius is closed and either a constant rate or a constant pressure is specified at the inner wellbore radius. Standard finite-difference techniques are used to solve implicitly for new reservoir pressures each timestep. The iterative scheme presented by van Poollen[5] is used to handle the nonlinearity introduced by the variance of real gas properties.

In addition to functioning as a conventional radial gas model, two special features are included that adapt SUGAR to the special flow properties of the Devonian shale, as currently understood. The reservoir porosity and permeability are considered functions of a uniformly distributed system of vertical natural fractures and the shale matrix. Typical fracture system values for porosity and permeability are believed to be 1% and 0.01 md, respectively. The remaining matrix volume of the shale reservoir is considered to have a porosity of 1 to 4% and an extremely low permeability, 10^{-3} to 10^{-7} md. The

TABLE 2—WELL 10056 HISTORY-MATCHING INPUT PARAMETERS

Well Data	
State	Ohio
County	Meigs
Formation	Lower Huron
Effective thickness, ft	190
Well depth, ft	3,399
Matching Parameters	
Radius of matrix element, cm	450
Fracture porosity, %	3.6
Fracture permeability, md	0.018
Matrix porosity, %	0.88
Matrix permeability, md	0.1×10^{-5}

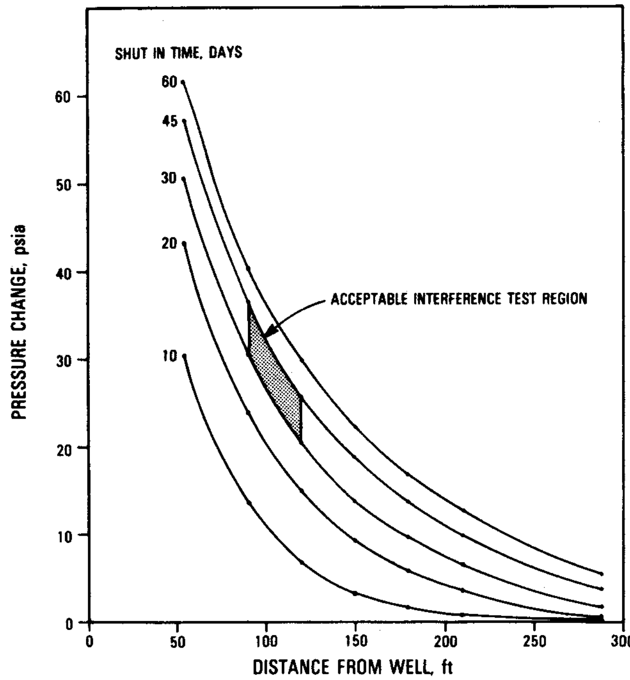

Fig. 3—Simulated pressure profiles, Well 10056.

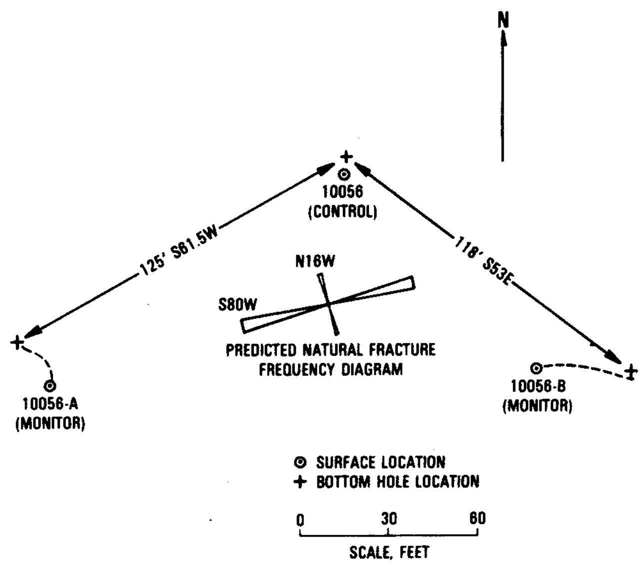

Fig. 4—Test well layout.

model reservoir consists of an array of cylindrical elements representing the shale matrix. This provides a dual-porosity system since gas flows to the surface of the shale matrix elements and then enters the fracture system to flow to a producing well. The Klinkenberg effect is included within the shale matrix as well as in the fracture system to account for non-Darcy effects caused by gas slippage. Pressure continuity is maintained at the interface between the fractures and the shale matrix.

The model also provides for the shale matrix to contain adsorbed gas on the walls of the pores as described by "sorption isotherms" such as those of Thomas and Frost.[6] The amount of gas adsorbed can readily be calculated from the shale volume, density, and existing pressure, since isotherm curves give the volume of gas adsorbed per unit mass as a function of pressure. The simulator assumes that as pressure is reduced within the shale matrix, gas is desorbed from pore walls according to the isotherm. This desorbed gas thus enters the matrix porosity as free gas, which can then flow through the matrix into the fracture system and subsequently to a pressure sink created by a producing well.

Table 2 lists history-matching parameters for Well 10056 that best fit the 30-day pressure buildup data and the 22-year production performance history. These parameters then were used to predict the reservoir pressure response at various distances resulting from various Well 10056 shut-in times (Fig. 3). The assumptions that at least 20 to 30 psi [138 to 207 kPa] of pressure-buildup response was required for interference-test analysis with the SUGAR model, and that 30 to 45 days of buildup time were available under the test budget constraint, identified an area in Fig. 3 as acceptable for testing. This region of the plot then defined the corresponding offset-to-base-well spacing range of 90 to 120 ft [27.4 to 36.6 m]. The offset well spacings and corresponding approximate interference-test durations were planned on the basis of these simulations.

Test Site Preparation

The active field phase of the experiment began with the drilling of the offset wells. The wells were drilled primarily on air, and by use of standard techniques to drill relatively straight holes to maintain control over the well-to-well distances in the target formation. On Well A, drilling progressed normally on air to 1,632 ft [497.4 m], where an unexpected water influx forced a temporary conversion to mud drilling down to the planned 8⅝-in. [21.9-cm] protection casing seat at 2,130 ft [649.2 m]. At that point, the rig reverted to air and drilled through Devonian shale to the core point at 2,914 ft [888.2 m]. Coring of the zone of interest was started with a 3½- × $7\frac{27}{32}$-in. [8.9- × 19.9-cm] prototype polycrystalline diamond cutter bit to take a 3½-in. [8.9-cm]-diameter directionally oriented core encased in a plastic sleeve, using an air and surfactant mist as coring fluid. The prototype bit performed flawlessly for a 58-ft [17.7-m] run and 18 ft [5.5 m] of the second run, at which point penetration approached zero. When the short core was pulled, the bit was found to be essentially destroyed by what was suspected to be junk in the hole. A succession of magnet, toothbit, and junk basket trips confirmed that suspicion and recovered the fragmented remains of a pipe tong die. Coring then resumed with a conventional diamond bit and recovered another 366 ft [111.6 m], for a total of 442 ft [134.7 m] of oriented core across the shale production interval. Well A was then drilled out to a total depth (TD) of 3,490 ft [1063.8 m] in the top of the Onondaga limestone underlying the shale. The well was logged by use of a gas-filled hole suite, including gamma ray, compensated density, temperature, audio, induction, and caliper surveys. A directional survey established the wellbore configuration and the bottomhole location.

The rig then was skidded across the location to drill offset Well B, which was drilled, logged, and surveyed

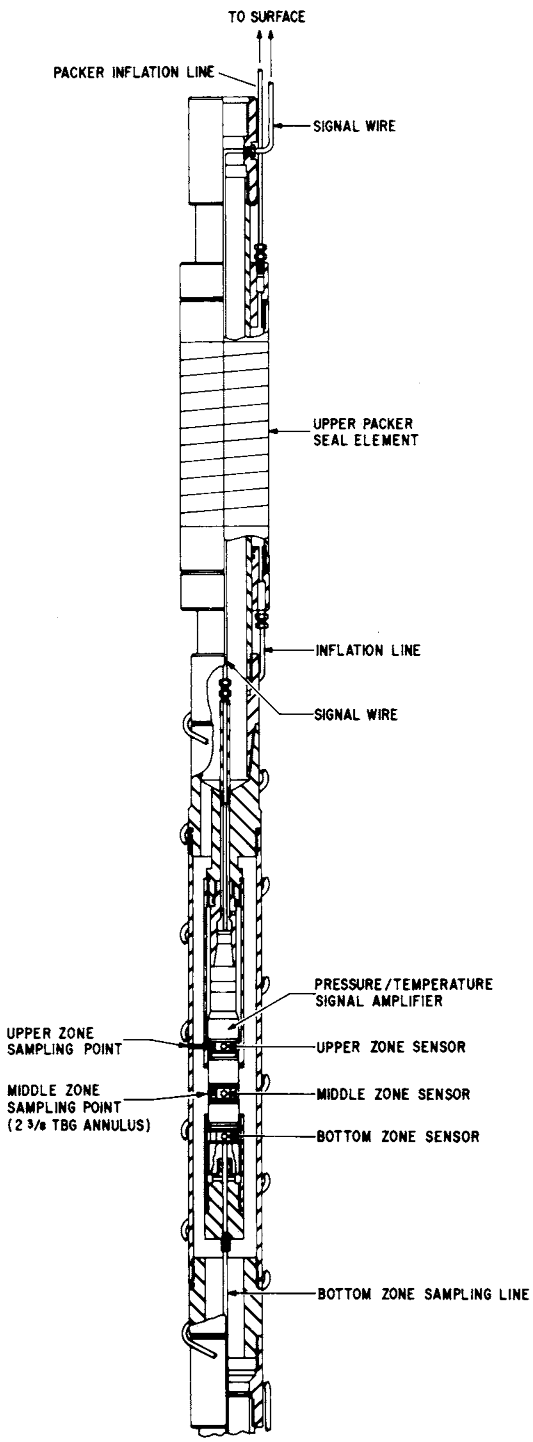

Fig. 5—Triple packer/sensor assembly.

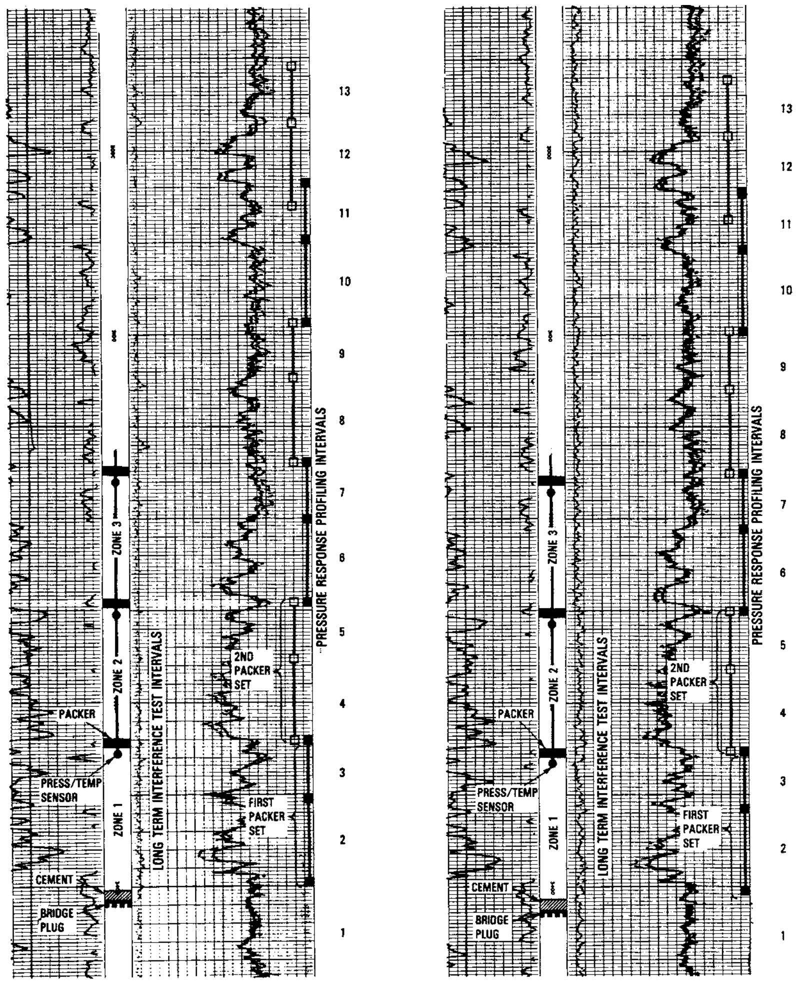

Fig. 6—Gamma ray/density logs and OWT packer settings.

with no significant problems. It also was completed with a protection casing string in the top of the shale section, leaving the reservoir interval as open 7⅞-in. [20-cm] hole to TD at the Onondaga. Both offsets thus bracketed the completion interval of the control well. Fig. 4 shows the surface and bottomhole locations of the three OWT wells, and a rose diagram of the test interval fracture trends as determined from core analysis of Offset Well A.

Instrumentation

The drilling rig was released and replaced with a smaller workover unit to prepare the wells for the planned reservoir interference tests. The tools and instrumentation required to monitor reservoir pressure in and to control the flow rate of the base well and to monitor the expected pressure responses at the offsets were assembled at the field site. Since the control well had originally been completed openhole across the entire lower Huron shale interval with a borehole shot and subsequent wall damage, packer seats were assumed unavailable and specific zone pressure isolation was impossible. Thus, the entire 1,288-ft [392.6-m] openhole interval across both productive and nonproductive shales was open for production and pressure commingling. Because of these constraints, a single downhole monitoring pressure gauge, a sensitive downhole quartz pressure sensor and surface recording device with ~0.01-psi [~0.07-kPa] resolution was inserted into the slotted tubing set through the completion interval. The sensor was set at a depth of 3,350 ft [1021.1 m], corresponding to the bottom long-term test zone in the offsets. The gauge remained at that position for the duration of the interference test.

The two offsets were each equipped with triple inflatable openhole packer assemblies, including sensitive temperature/pressure sensors to monitor and to record on the surface data from between and below the packers as shown in the tool schematic (Fig. 5). These assemblies were very versatile in that the individual packer spacings could be set to any desired distance by inserting sections of 2⅜-in. [6.0-cm] tubing between the elements. The assemblies were tubing-run and pressure-set with a ¼-in. [0.6-cm] steel nitrogen line strapped to the outside of the work string. Also strapped to the tubing was the single conductor wire that relayed the sensor signals to the data processors and recorders on the surface.

The signals from the seven downhole sensors were processed through counters, calculator/clocks, plotters,

TABLE 3—PRESSURE RESPONSE PROFILING RESULTS

Well 10056A				Well 10056B		
Test Zone (ft)	Shut-In Time (hours)	Buildup Pressure (psi)	Test Interval	Test Zone (ft)	Shut-In Time (hours)	Buildup Pressure (psi)
3,400 to 3,490	42.72	17.5	1	3,404 to 3,490	40.0	475.4
3,355 to 3,395	42.72	440.3	2	3,360 to 3,400	40.0	450.1
3,324 to 3,350	42.72	321.5	3	3,330 to 3,356	40.0	443.6
3,278 to 3,318	60.32	432.9	4	3,284 to 3,324	46.77	310.8
3,248 to 3,274	60.32	29.9	5	3,254 to 3,280	46.77	266.5
3,203 to 3,243	16.53	259.2	6	3,208 to 3,248	40.50	493.7
3,172 to 3,198	16.53	18.5	7	3,178 to 3,204	40.50	490.2
3,127 to 3,167	24.17	43.8	8	3,132 to 3,172	34.65	25.3
3,096 to 3,122	24.17	17.6	9	3,102 to 3,128	34.65	22.7
3,051 to 3,091	22.60	99.1	10	3,056 to 3,096	22.07	20.8
3,020 to 3,046	22.60	28.2	11	3,026 to 3,052	22.07	19.2
2,988 to 3,028	17.97	19.7	12	2,994 to 3,034	19.23	337.2
2,957 to 2,983	17.97	16.4	13	2,964 to 2,990	19.23	30.8

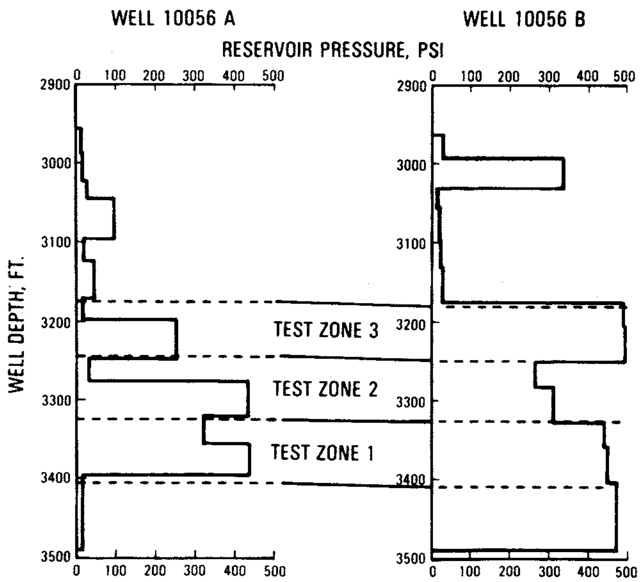

Fig. 7—Pressure response profiles.

and printers in the instrumentation trailer and were produced on both hard copy and magnetic tape for later analysis. The surface system also was flexible and performed well, despite some short data outages during severe thunderstorms later during the interference testing. Hard copy was printed for continual on-site test performance monitoring and the tape record was used for permanent data storage and later interference-test analysis.

Interference-Test Interval Selection

As illustrated by the gamma ray/density log curves (Fig. 6), the lower Huron lithology varies back and forth from gray (low gamma, higher-density) to brown (higher gamma, lower-density) shale. The brown shale stringers are organically rich, containing up to 15 vol% kerogen. This waxy material contains gas in solution (sorbed), and is considered the primary source for shale gas production. It also has been established that natural fractures are needed to provide measurable permeability to shale, that the fractures can exist in both gray and brown stringers, and that most such fractures are small and not readily detectable through log analysis. For these reasons straddle packers and short pressure buildup tests were used to identify permeable layers prior to the interference-test series.

Detailed reservoir pressure response profiles of both offset wells' productive intervals, covering the section from about 2,950 ft [899.2 m] to TD, were performed in Wells A and B. The packer assembly and pressure/temperature packages were made with 40-ft and 26-ft [12.2- and 8-m] spacings between the 4-ft [1.2-m] (effective) seal elements of the bottom/middle and middle/upper packer pairs, respectively, in both assemblies. These sets were chosen on the basis of log analysis and represented compromise spacings to isolate pressure response of the organic-rich and -lean shale intervals. Fig. 6 shows the gamma ray/density logs and the pressure response packer settings as well as other test data. The assemblies were run into both offsets and performed as planned, once "debugged." Minor equipment problems resolved during the pretest phase included packer element leaks and a signal failure caused by abrasion of the sensor wire strapped to the tubing string.

As shown in Fig. 7 and Table 3, reservoir pressure responses in Wells A and B ranged from essentially zero in some of the gray shales to 494 psi [3406 kPa] in a highly organic section of Well B. The degree of response can be correlated to the effective reservoir gas flow capacity—i.e., gas source and natural fractures—since the permeability of unfractured shale matrix is negligible. Some permeability streaks are present in both wells, but others show up in only one of the offsets. This shows that fracture density varies from layer to layer, and that generally the brown shale intervals are productive and the gray layers are not. Apparently, high fracture density increases the chances of both wells intersecting the fracture network in a given layer, while lower density decreases the intersection probability. The response profiles were then used to select three zones that represented common permeability intervals across the test site. The selection of the interference-test zones completed the pretest openhole evaluation of the offsets.

TABLE 4—RESERVOIR INTERFERENCE-TEST SUMMARY—BUILDUP/DRAWDOWN PRESSURES

		Pressure Buildup		Pressure Drawdown	
Test Zone	Test Interval (ft)	Initial (psi)	Final (psi)	Initial (psi)	Final (psi)
Well 10056-A					
1	3,324 to 3,404	441.7	587.4	587.4	463.4
2	3,248 to 3,320	305.9	389.2	389.2	256.3
3	3,176 to 3,243	282.3	374.2	374.2	234.1
Well 10056-B					
1	3,329 to 3,410	499.2	598.2	598.2	519.2
2	3,253 to 3,325	491.9	588.7	588.7	516.2
3	3,181 to 3,248	486.9	575.8	575.8	475.0
Well 10056—Control					
—	2,106 to 3,394	255.2	593.9	593.9	268.2

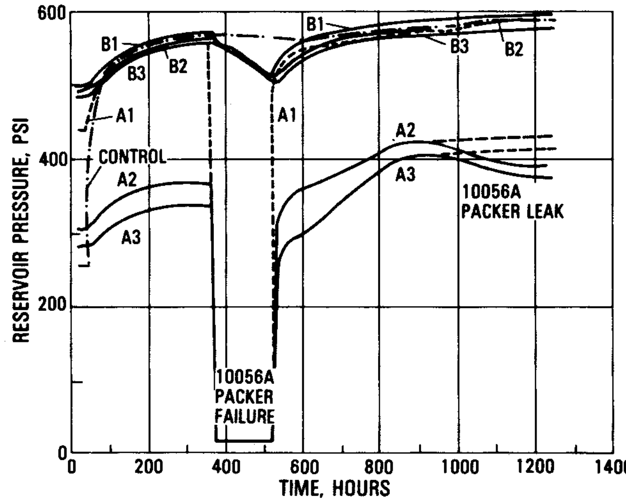

Fig. 8—Pressure buildup test data.

Interference Test

The response profile assemblies were retrieved to permit the plugging back of both offsets to set the lower bounds for the lowest test interval. The packer spacings were changed to bracket the selected long-term test zones and were then run back into the offsets to isolate 80-, 72-, and 67-ft [24.4-, 22.0-, and 20.4-m] intervals in Well A and 81-, 72-, and 67-ft [24.7-, 22.0-, and 20.4-m] intervals (Fig. 6) in Well B.

The individual zones in the offsets were shut in for 3 weeks to set the baseline for the interference test. During that time the interval pressures in both wells stabilized, while the control well, Well 10056, continued to flow into the pipeline at a nearly constant 250-psi [1724-kPa] bottomhole pressure (BHP). Table 4 shows the stabilized pretest pressures as well as the later buildup and drawdown initial and final pressures. Note that after 22 years' production, the flowing reservoir pressure around the control well had declined from the initial static 675 psi [4654 kPa] to 442 psi [3047 kPa] and 499 psi [3440 kPa], respectively, at Well A and B locations.

The long-term buildup test was started by shutting in the control well at the surface. The shut-in continued for 7 weeks, while the control well BHP rose from 255 to 593 psi [1758 to 4089 kPa]. Pressure response arrival times at the offsets varied with bottom zone sensor in Well A monitoring a first response 30 minutes after the control well was shut in. Fig. 8 shows the plotted pressures recorded during the long-term buildup. The test ran longer than planned because of a packer failure in offset Well A that allowed all three zones to go to atmospheric pressure. The field remedial action required a little more than 6 days before the packers were reset, and about 13 more days passed before the reservoir pressures regained the levels recorded prior to the packer blowout.

Following the buildup, the control well was opened and placed on production at constant pressure to start the drawdown interference test designed both to complement and to replicate reservoir data derived from the buildup test. The well was flowed into the pipeline and held at approximately 240-psi [1655-kPa] backpressure with a portable production tester for the 5 weeks' drawdown.

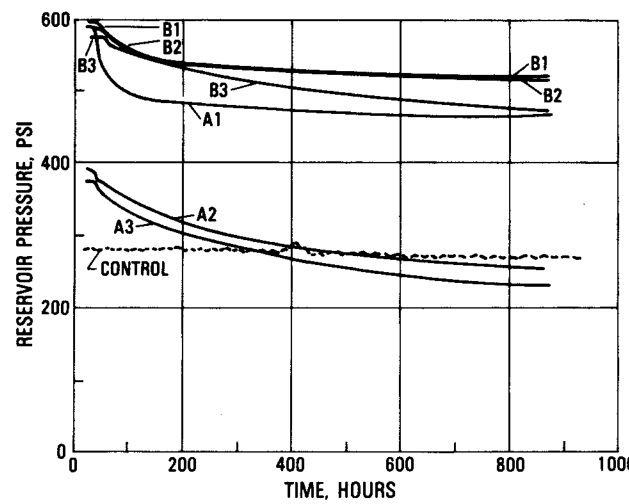

Fig. 9—Pressure drawdown test data.

During this period the production rate gradually declined to a stabilized rate. The offset well pressure response vs. time is shown in Fig. 9 and Table 4 lists initial and final pressure values.

The test series concluded with a short-term pressure pulse test. The control well was alternately produced and shut in through three cycles, consisting of 24 hours' flow followed by 24 hours' no flow. The pulse test was designed to isolate and to measure effects of the natural fracture system, since the long-term data measured the effective combined fracture/matrix properties of the shale. Later data analysis confirmed this separation of dual porosities and permeabilities through long- and short-term interference tests. The response of the reservoir to the pressure pulses is shown in Fig. 10.

Data Analysis and Results

The numerical analysis of interference data gathered during the buildup, drawdown, and pulse tests consisted of history-matching the field data to predictions from the computer codes SUGAR and SUGARMD[4] (an enhanced

TABLE 5—OFFSET WELL TEST RESULTS

Numerical Analysis of Fracture Permeability and Porosity

Zone	*kf* Buildup Type Curve (md)	*kf* Buildup Semilog (md)	*kf* Drawdown Type Curve (md)	*kf* Drawdown Semilog (md)	ϕf Buildup Type Curve (%)	ϕf Drawdown Type Curve (%)
Well 10056A						
1	0.03850	0.04938	0.07980	0.06930	0.050	0.007
2	0.00135	0.00153	0.00350	0.00314	0.005	0.001
3	0.00146	0.00143	0.00350	0.00327	0.005	0.001
Well 10056B						
1	0.04370	0.04776	0.06780	0.06350	0.00138	0.00051
2	0.00405	0.00559	0.00843	0.00784	0.00025	0.00015
3	0.00059	0.00076	0.00077	0.00081	0.00003	0.00003

Numerical Analysis of Fracture Properties

Well 10056 (Control)	*kf* Semilog Analysis (md)	*kf* Type Curve Analysis (md)	ϕf Type Curve Analysis (%)	Skin Factor	
				Semilog	Type Curve
Shot zone	0.0187	0.0200	0.09	−2.6	−2.0

Special Core Analysis Matrix Properties—Well 10056A

Zone	*km* Core Analysis (md)	ϕm Core Analysis (%)
1	0.00001	1.20
2	0.00001	1.12
3	0.00001	0.99

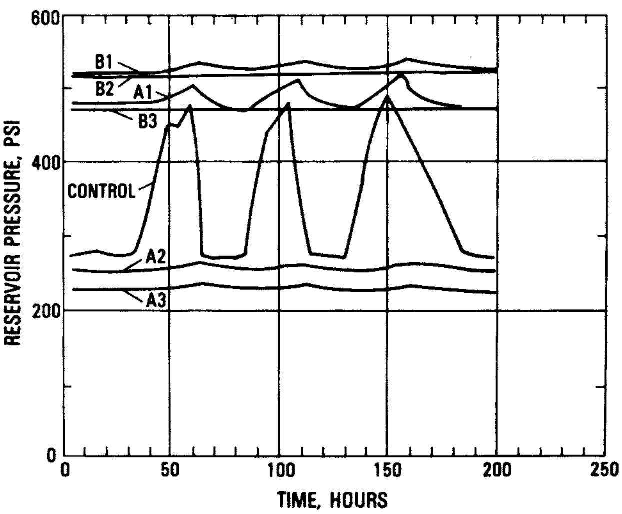

Fig. 10—Pressure pulse test data.

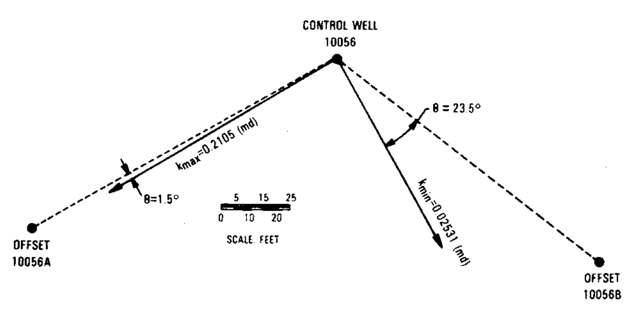

Fig. 11—Reservoir permeability anisotropy.

version of the shale model capable of simulating the effects of induced hydraulic fractures, multiple wells, and reservoir anisotropy). Processed data included results from the interference test, core analysis, and other available shale and field information. Detailed descriptions of the specific procedures of OWT data processing and analysis have been provided previously,[7,8] and are only summarized here.

Table 5 lists a summary of numerical results of the OWT analyses including numerically derived fracture permeabilities and dual porosities as well as matrix properties from core analysis for the three shale intervals tested. The permeability of the unfractured shale matrix was difficult to measure in the laboratory, as shown by the range of values. Battelle Columbus Laboratories reported values (derived from Well 10056-A core) from 0.0000002 to 0.00175 md, while Core Laboratories Inc. found matrix permeabilities for the three test zones to be close to 0.00001 md. The latter are considered representative and were used in the interference-test analysis.

As a test of data quality, a sensitivity study was conducted and documented[7,8] on the two-dimensional history-match parameters for Zone 1 of Wells A and B. Pressure-vs.-time plots were generated through history matching with laboratory and field data. Fig. 11 shows one of these plots for Well A as an example match. The sensitivity analysis focused on those parameters fixed by precise core laboratory measurements and on parameters that varied widely across the formation tested in the field.

A few of the sensitivity effects are reviewed here. As an example of sensitivity study output, Fig. 12 shows sensitivity of pressure data to the fracture porosity parameter to be slight. The effects of mean permeability and anisotropy showed that changing the anisotropy ratio

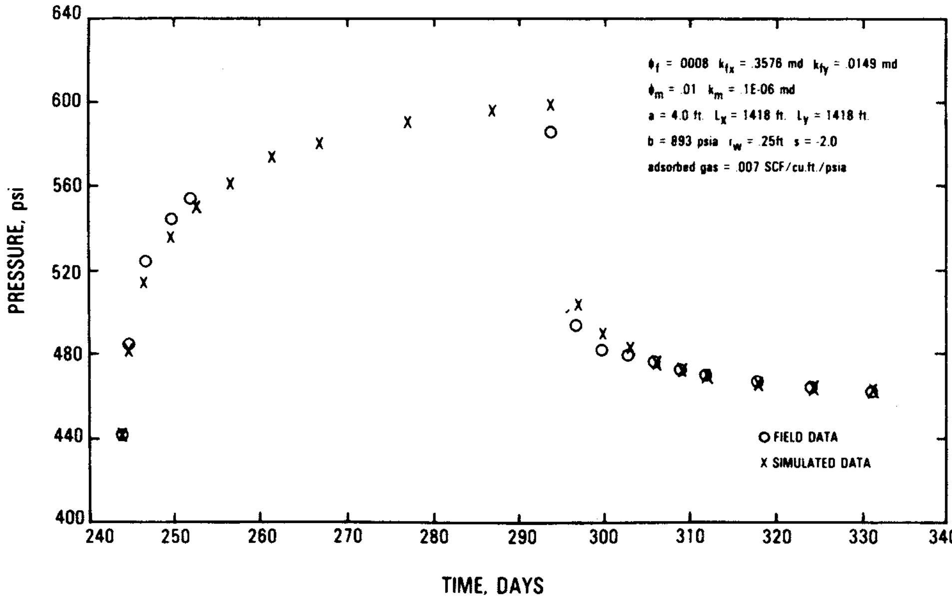

Fig. 12—History match of interference data, Zone 1, Well 10056A.

from 24 to 10 affects Well A pressure response only slightly but significantly reduces the response at Well B. Increasing the mean permeability from 0.0245 md to 0.0700 md significantly increases the drawdown rate at both offsets and alters the shape of their buildup curves. Sensitivity of pressure response to fracture spacing shows the entire pressure-time curve to shift downward when spacing is doubled.

This analysis shows little sensitivity to fracture porosity and high sensitivity to sorbed gas, natural fracture spacing, and permeability anisotropy. The study identified those parameters that contribute significantly to shale reservoir performance and improved confidence in the use of SUGAR/SUGARMD for interference-test analysis.

The reservoir has two distinct permeability trends. The primary trend is S60°W and is the direction of maximum fracture permeability, and the secondary trend is S30°E, which shows the minimum permeability direction (Fig. 13). The simulator runs determined the k_{max}/k_{min} ratio to be 8.3:1, indicating elliptical reservoir drainage for area shale wells. The mean drainage area radius of Well 10056 was calculated to be about 1,300 ft [396.2 m] and the drainage volume to be about 8.2 MMcf [2.3×10^5 m^3]. Reservoir permeability and gas transport within the shale are functions mainly of the natural fracture system,

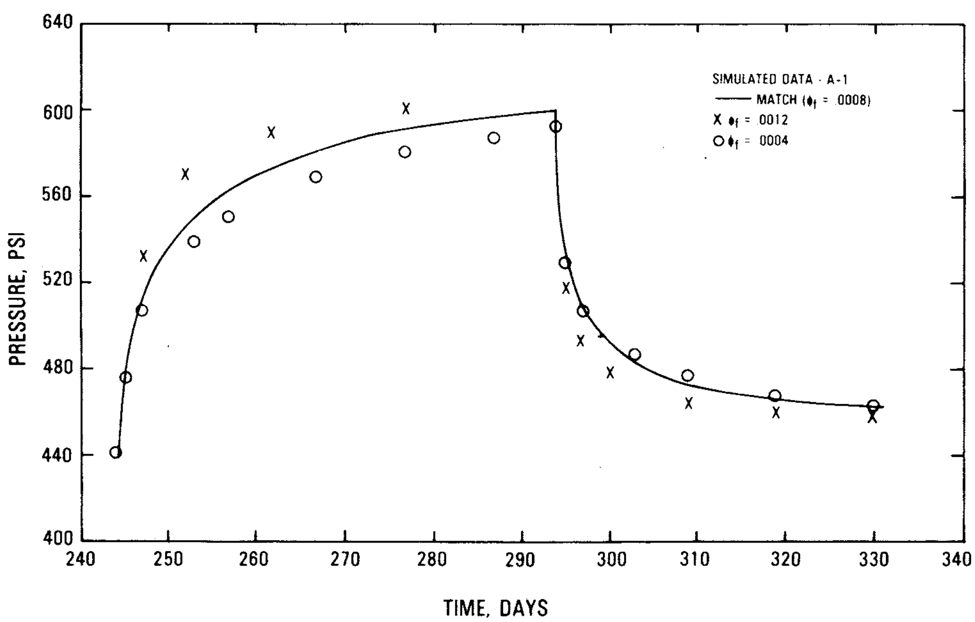

Fig. 13—Effect of fracture porosity on interference data, Zone 1, Well 10056A.

while gas storage is provided primarily by the unfractured matrix portion of the reservoir. Laboratory outgassing studies performed on offset Well A core material indicate that the reservoir gas is stored in solution in the solid organic component (kerogen) of the shale matrix and is gradually released as free gas toward the native fracture system as a function of reservoir pressure drop. This mechanism makes up the shale dual-porosity system: (1) sorbed gas in the solid matrix and (2) free gas in matrix pores and the fracture system. The dual-porosity concept was confirmed by comparing laboratory-derived matrix porosity and gas constant to the computer-assisted analysis of the field test data.

The engineering analysis also provided new qualitative information on the Devonian shale in Meigs County. The shale reservoir gas flow regime can be characterized by a naturally fractured matrix exhibiting dual porosities, and gas flow can be simulated by pseudosteady-state gas transfer from the matrix to the fracture system. The pressure response profiling measurements established that the alternating organic-rich and -lean shale layers have very limited vertical communication, as shown by the widely different pressures measured across the reservoir interval. The wells in the test area produce about 90% of their gas from the 80-ft [24.4-m] organic-rich interval (Test Zone 1) near the bottom of the shale section, which represents approximately 16% of the gross 500-ft [152.4-m] reservoir interval commonly completed in the area. These intervals exhibited rapid and strong pulse test response, indicating fairly dense natural fracturing with low fracture porosity and permeability. Responses in the upper sections (Zones 2 and 3) were less pronounced because of reduced fracturing, very low porosity and permeability, and wellbore storage dominating pressure interference effects.

Finally, as an additional check on the interpretation of interference data by the SUGAR and SUGARMD reservoir simulators, a set of new type curves was generated (and fully documented[7,8]) for analyzing the pressure data. As shown in the reference reports, generally good agreement between the two analysis techniques was obtained, thus increasing confidence in the model approach described here.

Conclusions

The offset well test conducted in the Devonian shale of southern Ohio has provided new reservoir performance information. The shale reservoir is anisotropically fractured and is drained in a highly elliptical pattern as a result. The extent of development of the native fracture system in the area is very significant, demonstrated by the measured 90% total gas production coming from a single fractured organic-rich zone representing only 16% of the commonly completed reservoir interval. Gas industry production practice in the Devonian shales is generally based on the belief that shale wells drain in a conventional circular manner. However, the information from the offset well interference test indicates that development wells drilled to take advantage of the elliptical drainage pattern could substantially improve the overall gas recovery from the shale with fewer wells. The interference test showed that relatively high reservoir pressures occur close to existing wells, such as Well 10056, which has been producing the fractured shale for 22 years. These pressures indicate that most gas still remains sorbed in the shale matrix and is available for recovery by infill development drilling.

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SI Metric Conversion Factors

$$\begin{aligned}\text{cu ft} &\times 2.831\,685 && E-02 = m^3\\ \text{ft} &\times 3.048^* && E-01 = m\\ \text{in.} &\times 2.54^* && E+00 = cm\\ \text{psi} &\times 6.894\,757 && E+00 = kPa\end{aligned}$$

*Conversion factor is exact.

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